ELLEN F. ROSENBLUM
Attorney General

MARY H. WILLIAMS
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

April 29, 2013

Attention: Filing Center
Public Utility Commission of Oregon
550 Capitol Street NE, #215
P.O. Box 2148
Salem, OR 97301-2148
puc.filingcenter@state.or.us

Re: *In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff Investigation into Qualifying Facility Contracting and Pricing*
PUC Docket No.: UM 1610
DOJ File No.: 330-030-GN0240-12

On behalf of the Oregon Department of Energy, enclosed for filing with the Commission in the above-captioned matter are an original and five copies of the Reply Testimony of Philip Carver and Reply Testimony of Tom Elliot.

Sincerely,

Renee M France
Senior Assistant Attorney General
Natural Resources Section

Enclosures
RMF:jrs/#4160111
c: UM 1610 Service List (electronic copies only)

DOCKET NO. UM 1610
EXHIBIT: ODOE/400
WITNESS: PHILIP CARVER

Before the
PUBLIC UTILITY COMMISSION OF OREGON

OREGON DEPARTMENT OF ENERGY

Reply testimony of Philip Carver

April 29, 2013

Q. PLEASE STATE YOUR NAME AND ORGANIZATION.

A. I am Phil Carver with the Oregon Department of Energy (ODOE). I am the same witness as in ODOE/100.

Q. WHAT IS THE PURPOSE OF THIS REPLY TESTIMONY?

A. I will address adjustments to payments to Qualifying Facilities (QFs) (Issues 1A and 4A) for capacity credits, integration costs and savings of transmission losses, as well as contract renewal (Issue 1C), the appropriate wholesale electricity hub (Issue 1A) and environmental attributes (Issue 2B).

Q. PLEASE SUMMARIZE YOUR REPLY TESTIMONY.

A. I support Staff's recommendation that any perceived mismatches between the value of purchases from QFs and the avoided cost payments made to QFs be addressed by making appropriate adjustments to the avoided cost payments, not by lowering the 10 megawatt (MW) eligibility cap for standard contracts. ODOE witness Tom Elliott will address the 10 MW eligibility cap in his testimony.

For the compliance filings, I caution against adjusting the avoided cost prices paid to wind and solar QFs to account for capacity contribution as recommended by Staff. This issue is technically complex and utilities have not addressed it correctly in their integrated resource plans (IRPs). I do support adjusting for the integration costs of wind generation as the IRP analysis of this issue is more mature. The determination of the value of capacity contributions and integration costs is likely to trigger evidentiary proceedings when avoided cost rates are set, at least initially.

If the Commission decides to explicitly address the capacity credit for wind, it should also do so for solar photovoltaic (PV) QFs. Solar PV QFs should receive at least a 30 percent capacity credit until the electric companies have calculated the solar capacity contribution. I recommend that solar QFs not be charged for integration until the electric companies have demonstrated there are material integration costs for solar generation.

I support OneEnergy's recommendations that QFs at or below 3 MW that are connected directly to the electric company's distribution system receive a 3.9 percent adder for avoided transmission losses and should receive longer fixed-price contracts. Instead of OneEnergy's recommendation for a 25-year fixed-price contract, however, I recommend maintaining the current contract term of up to 20 years, modified to allow QFs up to 3 MW to receive fixed prices throughout the entire term and not just the first 15 years.

I support the Renewable Energy Coalition's ("Coalition") recommendation that existing QFs renewing their contracts receive resource deficiency pricing for the next contract, up to a length set by the Commission.

As a change to my previous testimony, I recommend using either the California-Oregon Border wholesale market hub or the Mid-Columbia hub, based on QF location, to set prices during the resource sufficiency period.

Finally, I recommend moving Issue 2B (definition of environmental attributes) into phase two of this docket.

Q. PLEASE SUMMARIZE YOUR VIEWS ON CALCULATING CAPACITY CREDITS FOR WIND AND SOLAR PV QFS.

A. The capacity credits for wind in the electric companies' IRPs deserve more scrutiny before the values are appropriate for an avoided cost compliance filing. If the Commission chooses to address capacity credits explicitly, it should insist that the values are calculated using an effective load carrying capability (ELCC) method or other method that provides equivalent *annual* reliability under two scenarios – one with planned levels of wind and the other without such resources. The Commission should expect that requiring an explicit capacity credit for wind will trigger an evidentiary proceeding when avoided cost rates are set, at least initially.

If the Commission requires an explicit capacity credit for wind, it should also do so for solar. These are the two QF resources with substantial variability. Also, these two resources are likely to be the dominant renewable sources through 2025.

Q. WHAT CAPACITY CREDIT DO YOU RECOMMEND FOR SOLAR PV QFS?

A. Current estimates of solar capacity credits in electric companies' IRPs, to the extent they exist, are unreliable. Until such time as electric companies provide ELCC or other reliable values, the Commission should order the companies to assume a 30 percent capacity credit for solar PV systems.

Q. WHAT IS THE BASIS OF YOUR PROPOSED 30 PERCENT CAPACITY CREDIT VALUE FOR SOLAR?

A. This value is for Portland General Electric (PGE) from *Reaching Consensus in the Definition of Photovoltaics Capacity Credit in the USA: A Practical Application of Satellite-Derived Solar Resource Data, by* R. Perez, M.

Taylor, T. Hoff, and J.P. Ross.[1] This study uses a Garver approximation method. It is a conservative value because PGE's service area has more clouds than the Oregon service areas for PacifiCorp and Idaho Power. Also, PGE has a stronger winter peak which tends to reduce the ELCC capacity credit.

Q. WHAT INTEGRATION COSTS DO YOU PROPOSE FOR SOLAR PV QFS?

A. For the compliance filings, zero integration costs should be applied to solar PV QFs. At current levels of PV penetration there are virtually zero solar integration costs. Otherwise, electric companies' load forecasting methods would include forecasts of PV output. Electric companies do not make such forecasts even though there are several commercially available methods. Only when electric companies start forecasting PV output ahead of the hour and have credible methods to calculate the costs of solar integration should the Commission include solar integration costs as part of prices paid to QFs.

Q. WHY DO YOU PROPOSE THAT AVOIDED COST PRICES FOR SOLAR PV SYSTEMS NOT BE REDUCED BY THE COSTS OF WIND INTEGRATION?

A. Although the integration studies by the three electric companies for wind resources are generally reasonable, wind and solar integration costs are quite different. There is no reason to expect that wind integration costs will be an

[1] See the value on the graph for low PV penetration for PGE on page 6 of this article from an IEEE Journal on Selected Topics in Applied Earth Observations and Remote Sensing. Vol. 1, no. 1, 2008. (available at http://www.asrc.cestm.albany.edu/perez/publications/Utility%20Peak%20Shaving%20and%20Capacity%20Credit/Papers%20on%20PV%20Load%20Matching%20and%20Economic%20Evaluation/Towards%20reaching%20consensus-08.pdf)

accurate estimate of the costs for solar. As noted above, at current levels of penetration, solar integration costs are negligible.

Q. SHOULD THE COMMISSION KEEP THE CURRENT METHOD FOR CALCULATING CAPACITY CREDITS FOR QFS OTHER THAN WIND AND SOLAR?

A. Yes, the Commission should keep the current method for paying for capacity for resources other than wind and solar.

Q. WHY NOT EXPLICITY CALCULATE THE CAPACITY CREDIT FOR THESE OTHER RESOURCES?

A. Resources such as hydro and biomass are not variable like wind and solar. The existing method is an appropriate estimate for other resources.

Q. WHAT SHOULD THE COMMISSION ASSUME FOR INTEGRATION COSTS FOR THESE OTHER RESOURCES?

A. The Commission should assume zero integration costs for resources other than wind.

Q. WHAT SHOULD THE COMMISSION DECIDE ABOUT AVOIDED LINE LOSSES?

A. The Commission should adjust QF prices for reduced line losses for QFs up to 3 MW that are connected to the distribution system. These projects will save the energy losses from the transmission of electricity from remote power plants to load centers. In some cases these QFs will also save some distribution losses. I support using the 3.9 percent adjustment value proposed by Bill Eddie (OneEnergy/100, at 36 and 37, lines 1-5). As he notes, PacifiCorp has used this value for the company's transmission losses.[2] I concur that for PacifiCorp a 3.9 percent value is likely a conservative value. I also agree that if PGE or Idaho Power can demonstrate different values for transmission losses, then those values should be used for those utilities. I also support Bill Eddie's recommendation to use 3 MW as the eligibility cap for this line loss adder (OneEnergy/100 at 34). I agree that if these projects are connected to the distribution system they will generally displace local loads. In contrast, both larger QFs and avoided utility generation or power purchases are likely to require transmission to get power to loads.

To be clear, I support retaining the 10 MW eligibility cap for standard contracts, as explained by ODOE witness Tom Elliott (ODOE/500), and offering some additional support to projects 3 MW and under that are connected to the distribution system for the additional benefits that they provide relative to larger QFs and utility generation or power purchases.

Q. WHY WOULD YOU PROPOSE THIS CHANGE IN POLICY WHEN PREVIOUS COMMISSION ORDERS DECLINED TO CONSIDER AVOIDED TRANSMISSION LOSSES?

A. In Order No. 05-584 the Commission declined to include integration costs for any renewable resources for QFs at or below 10 MW. It also declined to consider avoided transmission losses. These un-included costs tend to offset each other. If the Commission moves to increase accuracy by including

---

[2] *PacifiCorp's Ten-Year Conservation Potential and 2012-2013 Biennial Conservation Target for its Washington Service Area*, pp. A3-6, A3-9 (Exhibit OneEnergy/115).

integration costs for some resources, it should also increase accuracy by recognizing reduced line losses for some resources.

Q. DO YOU SUPPORT THE COALITION'S PROPOSAL[3] THAT RENEWAL CONTRACTS SHOULD RECEIVE RESOURCE DEFICIENCY PRICES FOR THE WHOLE NEW CONTRACT?

A. That proposal has merit. PacifiCorp's 2011 Integrated Resource Plan Volume 1[4] filed as part of LC 52 notes the following on page 98:

> ***Qualifying Facilities (QF).*** *All QF that provide capacity and energy are included in this category. Like other power purchases, the capacity balance counts them at maximum system peak availability and the energy balance counts them by optimum model dispatch. It is assumed that all QF agreements will stay in place for the entire duration of the 20-year planning period. It should be noted that three of the QF resources (Kennecott, Tesoro, and US Magnesium) are considered non-firm and thus do not contribute to capacity planning.*

This quote indicates that PacifiCorp's IRP delays its commitment to firm resources based on the expectation of contract renewal. This is an appropriate planning principle. Under such planning, retail customers will avoid the costs of additional firm energy resources. The avoided cost price paid for renewed contracts should reflect that new firm resources are, or should be, deferred.

Q. WHAT TERM DO YOU PROPOSE FOR FIXED PRICES FOR QFS AT OR BELOW 3 MW THAT ARE CONNECTED TO THE DISTRIBUTION SYSTEM?

---

[3] Coalition/100,Lowe/21-22

[4] http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-MainDocFinal_Vol1-FINAL.pdf

A. I propose that these projects be offered fixed-price contracts for 20 years. Such contracts would more closely parallel electric companies' 20-year contracts for many renewable energy purchases.[5] The amount of power contracted under such projects will be a tiny fraction of retail loads. This means the risks to retail customers during the 16th year through the 20th year will be minimal, while the increased ability to finance such projects will be substantial. If the utility secures fixed-price natural gas contracts for the incremental new combined-cycle combustion turbine power plant, then substituting a fixed-price 20-year contract with a QF would add no fixed-price risk. Also, while the avoided natural gas-fired plant may require transmission upgrades, it is unlikely that QF projects at or below 3 MW would. This uncompensated benefit of the smallest QFs is likely to more than counterbalance the possible small increase in risk from longer terms for fixed prices.

Q. DO YOU PROPOSE CHANGES TO YOUR PROPOSAL TO ALWAYS USE THE MID-COLUMBIA WHOLESALE TRADING HUB FOR PRICES DURING THE RESOURCE SUFFICIENCY PERIOD?

A. Yes, the California-Oregon Border (COB) price may be more appropriate for QFs in southern Oregon. Trading hub price differentials exist because of transmission constraints. If a QF is located below the transmission constraint, the electric company would have the ability to resell that power at the higher

[5] OneEnergy/100, Eddie 39 at 3-9

COB price. This concept would only be applicable to QFs interconnecting with PacifiCorp.

Q. WHAT MIGHT BE THE APPROPRIATE DIVIDING LINE FOR SUCH A DISTINCTION?

A. I propose that QFs interconnecting to PacifiCorp lines south of either the Alvey transmission substation near Eugene or the Grizzly substation near Redmond receive prices based on the COB hub price. If PacifiCorp shows that there are recurring transmission constraints below these points, the Commission should consider moving the dividing line south. It is unlikely that there are commonly occurring transmission constraints between either Medford or Klamath Falls and the COB hub. Both cities sit virtually on top of the COB hub.

Q. WHAT SHOULD THE COMMISSION DECIDE ABOUT CONTRACT LANGUAGE DEFINING ENVIRONMENTAL ATTRIBUTES (ISSUE 2B)?

A. The definition of environmental attributes should be decided in phase two of this docket. We believe that consensus on this issue is possible if parties are given more time to develop and consider specific contract language.

Q. DOES THIS CONCLUDE YOUR REPLY TESTIMONY?

A. Yes.

DOCKET NO. UM 1610
EXHIBIT: ODOE/500
WITNESS: TOM ELLIOTT

Before the
PUBLIC UTILITY COMMISSION OF OREGON

OREGON DEPARTMENT OF ENERGY

Reply testimony of Tom Elliott

April 29, 2013

Q. PLEASE STATE YOUR NAME.

A. Tom Elliott. I am the same witness as in ODOE/200.

Q. WHAT IS THE PURPOSE OF THIS REPLY TESTIMONY?

A. I will be responding to OPUC Staff testimony regarding issue 5A (standard contract eligibility cap) and to the prior testimony and current resolution efforts on 6E (how contracts should address mechanical availability).

Q. DOES THE DEPARTMENT AGREE WITH OPUC STAFF'S TESTIMONY[1] REGARDING WHETHER THE COMMISSION SHOULD CHANGE THE 10 MW CAP FOR THE STANDARD CONTRACT? (ISSUE 5A)

A. Yes and no. We agree with Staff's recommendation to keep the eligibility cap at 10 megawatts (MW). However, we disagree with Staff's alternate recommendation to lower the cap to 3 MW if no adjustments are made to the avoided cost payments.

Q. COULD YOU PLEASE ELABORATE?

A. The Summary on p. 1 of Order No. 05-584 (Docket UM 1129) states:

> This Commission's goal has been to encourage the economically efficient development of these qualifying facilities (QFs), while protecting ratepayers by ensuring that utilities pay rates equal to that which they would have incurred in lieu of purchasing QF power.

This two-part goal is reiterated on p. 11 of that same order:

> We seek to provide maximum incentives for the development of QFs of *all* sizes, while ensuring that ratepayers remain indifferent to the QF power by having utilities pay no more than their avoided costs.

Much of the Staff testimony regarding the 10 MW eligibility cap relates to the second part of that goal: to set accurate avoided costs to protect ratepayers.

[1] Staff/100/Bless/35-38

The Department supports using accurate costs and protecting ratepayers, as described by ODOE witness Phil Carver (ODOE/400). However, we believe Staff's response testimony inadequately considers the first part of the Commission's goal: to encourage development of QFs.

Q. HOW WOULD A REDUCTION OF THE ELIGIBILITY CAP AFFECT QF DEVELOPMENT?

A. Reducing the eligibility cap would likely result in fewer small QF projects being developed in Oregon, as I discussed in my prior testimony on this issue (ODOE/200/Elliott/2-6). Having to negotiate a power purchase agreement (PPA) will result in higher transactions costs for a QF. These include direct legal costs of negotiation, and indirect costs passed on from the lender for contract review by legal and technical consultants. The higher transaction costs may cause some small QF projects not to be financially viable.

Additionally, requiring negotiated PPAs would significantly impact the financing and project development process. The Department's Small-scale Energy Loan Program (Loan Program), or any other lender, will not be able to assess the financial viability of a project, nor make a commitment to finance a project, until it can review the terms of a PPA, including prices and key clauses related to power delivery and any cause for default or termination. Without prices, a lender wouldn't be able to assess QF project revenues, and without knowing the revenues, the lender could not determine how much to lend or whether to lend to the QF.

Securing long term project financing is a critical step in the project development process. A QF developer needs a commitment for long term financing before securing construction financing and placing orders on long-lead-time equipment. Without a standard contract, a QF would need to negotiate a PPA, at its own expense, early in the process in order to find out if the project is viable and to be able to apply for financing. Some small QFs may choose not to risk this additional out-of-pocket legal expense just to determine whether their projects might be financially viable, and therefore may not move forward with them.

Q. WHAT IS THE LOAN PROGRAM'S EXPERIENCE WITH PROJECTS BETWEEN 3 MW AND 10 MW IN SIZE?

A. Half of the QF loan applications we have received since Commission Order No. 05-584 raised the limit for standard contract eligibility to 10 MW have fallen into the 3 MW to 10 MW capacity range. The Loan Program processed 14 QF loan applications during that time, seven of which were 3 MW or smaller and seven of which were between 3 MW and 10 MW[2]. If the eligibility cap had been 3 MW instead of 10 MW, half of our applicants would have had to incur additional costs to negotiate their PPAs. As stated in my response testimony, several of those same QF developers told us unequivocally that they did not believe their QF projects would have been built if they had to negotiate their PPAs.

Q. DO YOU QUESTION OTHER CONCLUSIONS MADE BY OPUC STAFF IN THAT SAME TESTIMONY?

[2] The Loan Program provided loans to 6 of the 14 applicants. Three of the six loans were for projects between 3 MW and 10 MW.

A. Yes. We disagree with the following premise in Staff's testimony at Staff/100/Bless/37, lines 13-15:

> Staff reasoned that a large, sophisticated developer capable of procuring the latest offering from these vendors is likely capable of negotiating a PPA.

First, our QF loan applicants have not been large project developers. They have been independent entities without the support of any large, sophisticated, well-capitalized development company. Second, our QF loan applicants have exhibited a broad range of experience and sophistication. Based on our discussions with QF loan applicants, we believe that all developers of QF projects up to 10 MW, regardless of sophistication, will need to retain legal counsel to negotiate a PPA.

Q. WHY DO YOU BELIEVE THAT ALL SMALL QFS, REGARDLESS OF SOPHISTICATION, NEED LEGAL SUPPORT TO NEGOTIATE CONTRACTS?

A. The Loan Program reviewed our QF loan history and interviewed several QF developers. Even our most experienced and sophisticated QF developer was very adamant about needing legal assistance in negotiating a PPA. We learned that PPA negotiation experience and expertise, and especially legal experience and expertise in that area, are specialized and expensive.

At least until the Loan Program had gained practical experience in financing QFs with negotiated PPAs, we would not take the risk of financing a QF project that did not have the requisite legal representation in negotiating the PPA.

Q. ARE THERE OTHER PORTIONS OF OPUC STAFF TESTIMONY TO WHICH YOU WANT TO REPLY?

A. Yes. Staff states at Staff/100/Bless/38, lines 1-3:

> Staff also notes that the solar, biomass and small hydro in PGE, PacifiCorp and Idaho Power's current portfolios are, for the most part, well under 3 MW.

While the utilities' current portfolios of small hydro may consist mainly of projects under 3 MW, a substantial amount of the small hydropower development in Oregon has been between 3 MW and 10 MW.

Q. HOW WOULD A 3 MW CAP FOR STANDARD AVOIDED COSTS AND STANDARD CONTRACTS FOR QFS AFFECT HYDRO PROJECTS?

A. A 3 MW cap on standard avoided cost prices and standard contracts would, in particular, affect irrigation canal projects and facilities added to non-power dams. Siting energy facilities on existing water infrastructure is the next wave of hydropower development due to its low environmental footprint and co-benefits. Promoting this development is one of the strategic water goals of the State under the 2012 Integrated Water Resources Strategy.[3]

Recent development history and the permitting pipeline show that a common scale of hydro project development in Oregon is between 3 MW to 10 MW. There are two 5 MW irrigation projects in Central Oregon: Central Oregon Irrigation District's Juniper Ridge project, which began operating in 2010, and the 45-Mile project on North Unit Irrigation Canal, which is still under

[3] *Oregon's 2012 Integrated Water Resources Strategy*, at http://www.oregon.gov/owrd/LAW/docs/IWRS_Final.pdf.
See Action 4B: Take Advantage of Existing Infrastructure to Develop Hydroelectric Power, page 49.

development. In addition, projects on existing federal dams in Oregon tend to have a nameplate capacity greater than 3 MW. For example, a new 8.3 MW facility will complete construction on Dorena Lake Dam in 2013. FERC issued a license for a 10 MW facility on Applegate Dam in 2009. PGE is currently proposing a 6 MW facility on Bowman Dam. Baker County is pursuing a 3.4 MW facility on Mason Dam. The Loan Program had financing discussions with all of these projects except for the Dorena Lake Dam and the PGE Bowman Dam.

Q. COULD YOU SUMMARIZE YOUR REPLY TESTIMONY ON THE ISSUE OF ELIGIBILITY CAP FOR STANDARD CONTRACTS?

A. The Department agrees with many other parties that the 10 MW eligibility cap for the standard contract should not be changed. Reducing the cap from 10 MW to 3 MW would almost certainly reduce the number of QF projects developed in Oregon. Had Commission Order No. 05-584 set a 3 MW cap rather than 10 MW, the Loan Program would have financed 50 percent fewer loans. It is not the sophistication of the QF developer that is important, but rather the time, uncertainty and costs that negotiating a PPA would introduce into the QF development and financing process that would reduce small QF development in Oregon. The balance the Commission sought in Order No. 05-584 between encouraging QF development and protecting ratepayers is best struck by retaining the 10 MW cap and making appropriate adjustments to the avoided cost prices to more accurately reflect the true costs and benefits of adding QFs to the electric companies' systems. ODOE witness Phil Carver makes recommendations for such price adjustments in his reply testimony.

Q. HOW DOES THE DEPARTMENT BELIEVE STANDARD QF CONTRACTS SHOULD ADDRESS MECHANICAL AVAILAILABILITY? (ISSUE 6E)

A. We appreciate the efforts underway among the parties to resolve this issue. The Department believes the resolution should adhere to the following principles:

1) Contract termination should not be the penalty for occasionally missing availability requirements. The Loan Program will not finance QFs if the PPA includes such a termination clause. (The Loan Program believes that chronic lack of availability and other contract non-performance by a QF is an entirely different matter, and acknowledges the utilities' potential need in those circumstances, which should be spelled out and well understood ahead of time, to sever its contractual relationship with such a QF.)

2) Any liquidated damages that the utility may assess a small QF:

- Should be based on the actual harm to the utility
- Should not in and of themselves imperil the ongoing economic vitality of the QF
- Should only be instituted after the QF has been properly notified and given ample opportunity for restitution

3) All three electric companies should adopt similar requirements.

Based on what we believe to be good faith efforts from all sides, the Loan Program is inclined to defer to other parties with first-hand experience operating and maintaining small generating projects to recommend specific mechanical availability guarantee percentages and number of allowable hours for scheduled maintenance.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE

I hearby certify that on April 29, 2013, I served the foregoing Reply Testimonies in Docket UM 1610 upon all parties of record in this proceeding by electronic mail only as all parties have waived paper service.

OPUC Dockets
Citizens' Utility Board of Oregon
610 SW Broadway, Suite. 400
Portland, OR 97205
dockets@oregoncub.org

Oregon Dockets
Pacificorp, dba Pacific Power
825 NE Multnomah Street, Suite. 2000
Portland OR 97232
oregondockets@pacificorp.com

Regulatory Dockets
Idaho Power Company
PO Box 70
Boise ID 83707-0070
dockets@idahopower.com

RNP Dockets
Renewable Northwest Project
421 SW 6th Ave., Suite. 1125
Portland OR 97204
dockets@rnp.org

Paul D. Ackerman **(C)**
Exelon Business Services company, LLC
100 Constellation Way Suite. 500C
Baltimore, MD 21202
paul.ackerman@constellation.com

Gregory M. Adams **(C)**
Richardson & O'Leary
PO Box 7218
Boise ID 83702
greg@richardsonandoleary.com

Daren Anderson
Northwest Energy Systems Company LLC
1800 NE 8th St., Ste. 320
Bellevue, WA 98004-1600
da@thenescogroup.com

Brittany Andrus **(C)**
Public Utility Commission of Oregon
PO Box 2148
Salem OR 97308-2148
brittany.andrus@state.or.us

Stephanie S. Andrus **(C)**
PUC Staff--Department of Justice
Business Activities Section
1162 Court St NE
Salem OR 97301-4096
stephanie.andrus@state.or.us

James Birkelund **(C)**
Small Business Utility Advocates
548 Market St. Ste. 11200
San Fransisco, CA 94104
james@utilityadvocates.org

Adam Bless **(C)**
Public Utility Commission of Oregon
PO Box 2148
Salem OR 97308-2148
adam.bless@state.or.us

Kacia Brockman **(C)**
Oregon Department of Energy
625 Marion St. NE
Salem, OR 97301
kacia.brockman@state.or.us

J. Laurence Cable
Cable Huston Benedict Haagensen & Lloyd LLP
1001 SW Fifth Ave. – Suite 2000
Portland, OR 97204-1136
lcable@cablehuston.com

Will K. Carey
Annala, Carey, Baker, et al., PC
Po Box 325
Hood River, OR 97031
wcarey@hoodriverattorneys.com

R. Bryce Dalley **(C)**
Pacific Power
825 NE Multnomah St., Suite 2000
Portland OR 97232
bryce.dalley@pacificorp.com

Melinda J. Davison **(C)**
Davison Van Cleave PC
333 SW Taylor, Suite 400
Portland OR 97204
mjd@dvclaw.com
mail@dvclaw.com

Megan Walseth Decker **(C)**
Renewable Northwest Project
421 SW 6th Ave #1125
Portland OR 97204-1629
megan@rnp.org

Bill Eddie **(C)**
One Energy Renewables
206 NR 28th Avenue
Portland OR 97232
bill@oneenergyrenewables.com

Loyd Fery
11022 Rainwater Lane SE
Aumsville, OR 97325
dlchain@wvi.com

J. Richard George **(C)**
Portland General Electric Company
121 SW Salmon St. 1WTC1301
Portland OR 97204
richard.george@pgn.com

John Harvey **(C)**
Exelon Wind LLC
4601 Westown Parkway, Suite 300
West Des Moines, IA 50266
john.harvey@exeloncorp.com

Diane Henkels **(C)**
CleanTech Law Partners PC
6228 SW Hood
Portland OR 97239
dhenkels@actionnet.net

Robert Jenks **(C)**
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205
bob@oregoncub.org

Kenneth Kaufmann **(C)**
Lovinger Kaufmann LLP
825 NE Multnomah Ste. 925
Portland, OR 97232-2150
kaufmann@lklaw.com

Matt Krumenauer **(C)**
Oregon Department of Energy
625 Marion St NE
Salem OR 97301
matt.krumenauer@state.or.us

David A. Lokting
Stoll Berne
209 SW Oak Street, Suite 500
Portland, OR 97204
dlokting@stollberne.com

Richard Lorenz **(C)**
Cable Huston Benedict Haagensen & Lloyd LLP
1001 SW Fifth Ave. – Suite 2000
Portland, OR 97204-1136
rlorenz@cablehuston.com

Jeffrey S. Lovinger **(C)**
Lovinger Kaufmann LLP
825 NE Multnomah Suite 925
Portland, OR 97232-2150
lovinger@lklaw.com

John Lowe
Renewable Energy Coalition
12050 SW Tremont Street
Portland OR 97225-5430
jravenesanmarcos@yahoo.com

Adam Lowney **(C)**
McDowell Rackner & Givson PC
419 SW 11th Ave., Suite 400
Portland, OR 97205
adam@mcd-law.com

Mike McArthur
Association of OR Counties
PO Box 12729
Salem,OR 97309
mmcarthur@aocweb.org

G. Catroina McCracken **(C)**
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205
catriona@oregoncub.org

Glenn Montgomery
Oregon Solar Energy Industries Association
PO Box 14927
Portland OR 97293
glenn@oseia.org

Thomas H. Nelson
PO Box 1211
Welches OR 97067-1211
nelson@thnelson.com

Kathleen Newman
Oregonians for Renewable Energy Policy
1553 NR Greensword Dr.
Hillsboro OR 97214
kathleenoipl@frontier.com
k.a.newman@frontier.com

Mark Pete Pengilly
PO Box 10221
Portland OR 97296
mpengilly@gmail.com

Elaine Prause
Energy Trust of Oregon
421 SW Oak St. #300
Portland, OR 97204-1817
elaine.prause@energytrust.org

Lisa F. Rackner **(C)**
McDowell Rackner & Gibson PC
419 SW 11th Ave., Suite 400
Portland OR 97205
dockets@mcd-law.com

Peter J. Richardson **(C)**
Richardson & O'Leary PLLC
PO Box 7218
Boise ID 83707
peter@richardsonandoleary.com

Toni Roush
Roush Hydro Inc.
355 E Water
Stayton, OR 97383
tmroush@wvi.com

Irion A. Sanger **(C)**
Davison Van Cleve
333 SW Taylor - Suite 400
Portland OR 97204
ias@dvclaw.com

Donald W. Schoenbeck **(C)**
Regulatory & Cogeneration Services, Inc.
900 Washington Street, Suite 780
Vancouver WA 98660-3455
dws@r-c-s-inc.com

John W. Stephens **(C)**
Esler Stephens & Buckley
888 SW Fifth Ave Suite 700
Portland OR 97204-2021
stephens@eslerstephens.com
mec@eslerstephens.com

Chad M. Stokes
Cable Huston Benedict Haagensen & Lloyd LLP
1001 SW Fifth Ave. – Suite 2000
Portland, OR 97204-1136
cstokes@cablehuston.com

Jay Tinker **(C)**
Portland General Electric
121 SW Salmon St 1WTC-0702
Portland OR 97204
Pge.opuc.filings@pgn.com

David Tooze
City of Portland – Planning & Sustainabiliy
1900 SW 4th Suite 7100
Portland, OR 97201
david.tooze@portlandoregon.gov

S. Bradley Van Cleve **(C)**
Davison Van Cleve PC
333 SW Taylor - Suite 400
Portland OR 97204
bvc@dvclaw.com

John M. Volkman
Energy Trust of Oregon
421 SW Oak St. #300
Portland, OR 97204
john.volkman@energytrust.org

Donovan E. Walker **(C)**
Idaho Power Company
PO Box 70
Boise ID 83707-0070
dwalker@idahopower.com

Mary Wiencke **(C)**
Pacific Power
825 NE Multnomah St, Suite 1800
Portland OR 97232-2149
mary.wiencke@pacificorp.com

(C)=Confidential

Renee M. France
Senior Assistant Attorney General
Natural Resources Section